CHAPTER 7 GENERATING ELECTRICITY FOR HAWAII

7.1 Overview

Hawaii's electricity is generated by the four electric utilities, non-utility generators, and the sugar industry. Most of this electricity is sold to consumers by the utilities. Hawaiian Electric Company, Inc., (HECO) serves the City and County of Honolulu (Oahu); Hawaii Electric Light Company, Inc., (HELCO) serves Hawaii County; the Kauai Electric Division of Citizens Energy Services (KE) serves Kauai County; and Maui Electric Company, Ltd., (MECO) serves Maui County and Kalawao County. MECO operates separate systems for Maui, Lanai, and Molokai.

Non-utility generators include NUGs that have negotiated power purchase agreements to sell all the power they generate beyond plant use to the utilities. Cogenerators produce electric power and process-heat for their own or contracted use and sell surplus power to a utility. Hawaii's sugar plantations generate electricity to power their operations and sell surplus electricity to the utility on their island. The utilities resell the power to their customers.

Four chapters in *HES 2000* address electricity issues in Hawaii. Chapter 7 focuses on electricity supply. Chapter 8 offers recommendations on ways to increase renewable energy use for electricity generation in Hawaii. Chapter 9 discusses ways to restructure Hawaii's electricity system by increasing competition. Chapter 11 includes discussion of ways that electricity demand can be reduced in Hawaii's buildings.

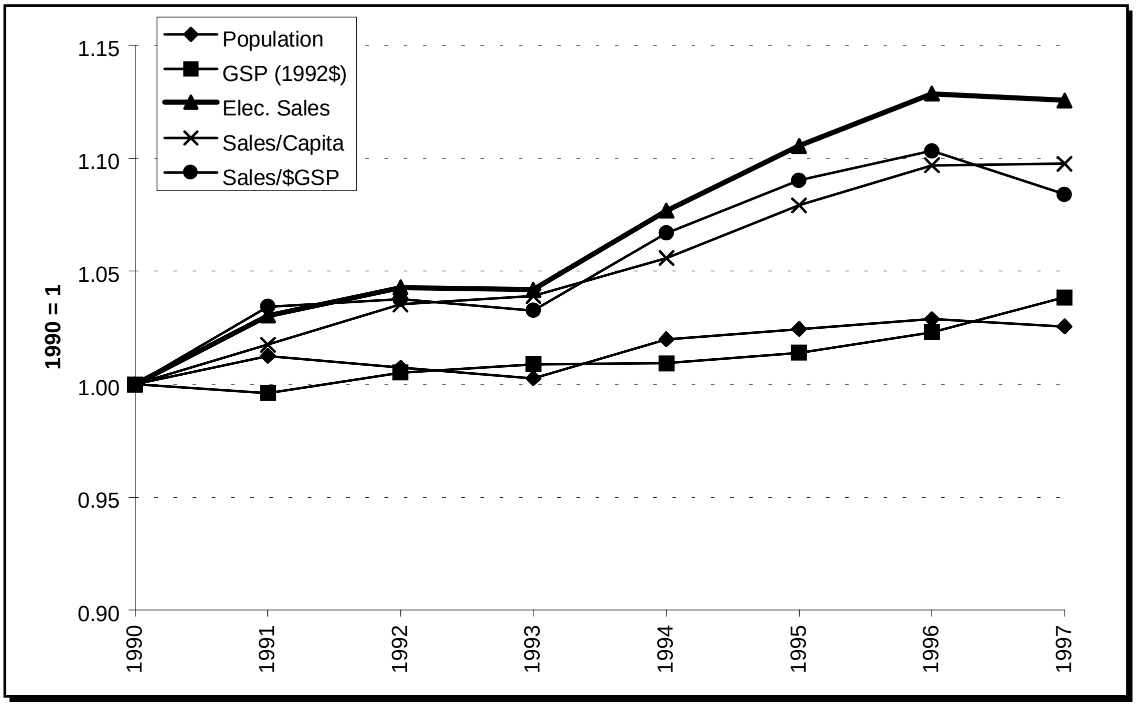
7.2 Hawaii's Electricity Challenges

Electricity is vital to modern life. Virtually all of Hawaii's citizens use electricity for essential functions such as lighting, water heating, refrigeration, air conditioning, ventilation, and cooling. At higher elevations, some Hawaii citizens even need heating. Electricity is used to operate home appliances, office machines, industrial equipment, communications systems, and other devices. A small number of electric vehicles charge their batteries with utility electricity.

7.2.1 Growing Electricity Sales

Electricity use grew faster between 1990 and 1997 than any other form of energy use. The slowdown in Hawaii's economy since 1991 was not evident in reduced electricity sales until 1997. As Figure 7.1 shows, increases in the sales of electricity outpaced growth in Hawaii's population and gross state product (GSP) during the period. By 1997, electricity sales were almost 13% greater than in 1990. The 15% growth in residential sales outpaced the 12% increase in commercial/industrial sales.

During the same period, Hawaii's de facto population grew about 1.1%, while GSP grew 3.8%. Electricity sales per capita grew 11.3%, and there was an 8.4% growth in electricity sales per real dollar of GSP.



Source: Utility FERC Forms 1 and Annual Reports, 1990–1997, DBEDT 1999

Figure 7.1 Hawaii Electricity Sales, De Facto Population, and GSP, 1990–1997

Hawaii's electricity intensity (kWh per dollar of GSP) is lower than the U.S. average. Hawaii's electricity intensity in 1997 was less than 0.3 kWh per dollar of GSP, approximately 70% of the 0.43 kWh per dollar of gross domestic product (GDP) for the nation as a whole. Figure 7.2, shows sales for each of the four utility systems for the period 1990–1997. MECO sales grew most rapidly, by 32%, HELCO sales increased 25%, Kauai Electric sales rose 11%, and HECO sales increased 9%.

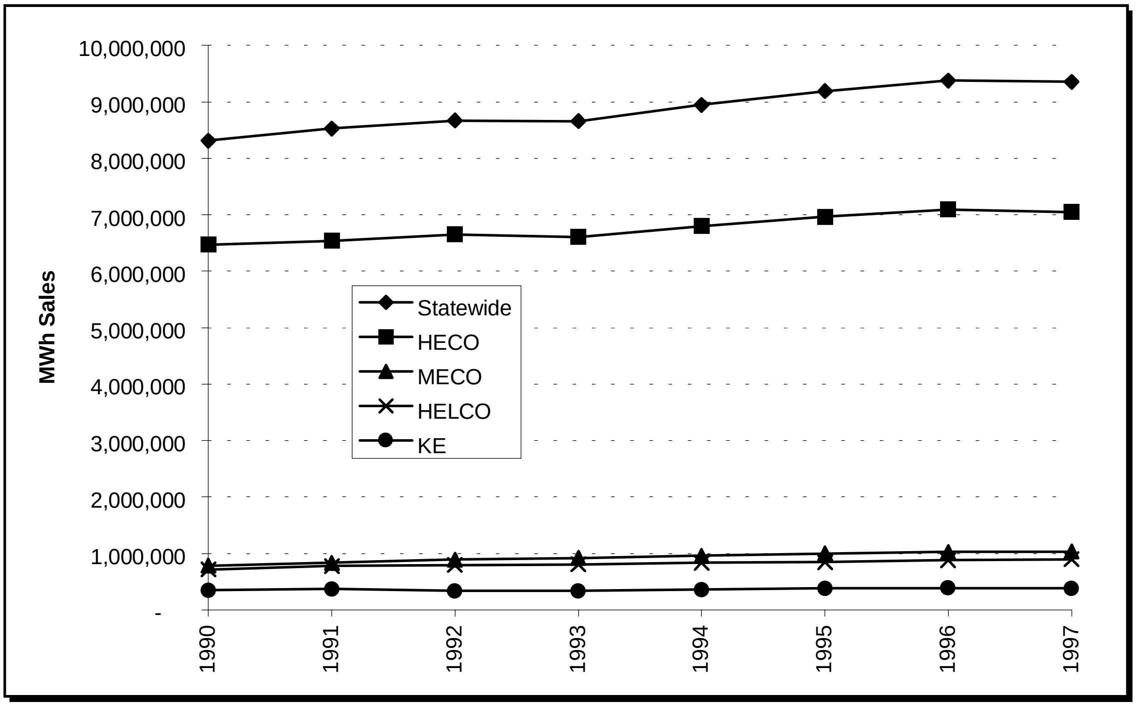
Figure 7.3, depicts the growth in electricity sales by rate classification from 1990 to 1997. Unfortunately, the rate classifications allow only a general analysis of the source of sales growth by sectors. Some large residential uses, such as master metered apartments or condominiums, are included in the commercial/industrial sector.

Despite the more rapid growth in sales on the neighbor islands, Oahu’s large population dominated statewide sales, and commercial/industrial sector sales were greater than residential sales on Oahu. Figure 7.4 shows the percentage of statewide electricity sales by rate classification and electric utility system in 1997.

7.2.2 The Rapidly Rising Cost of Electricity

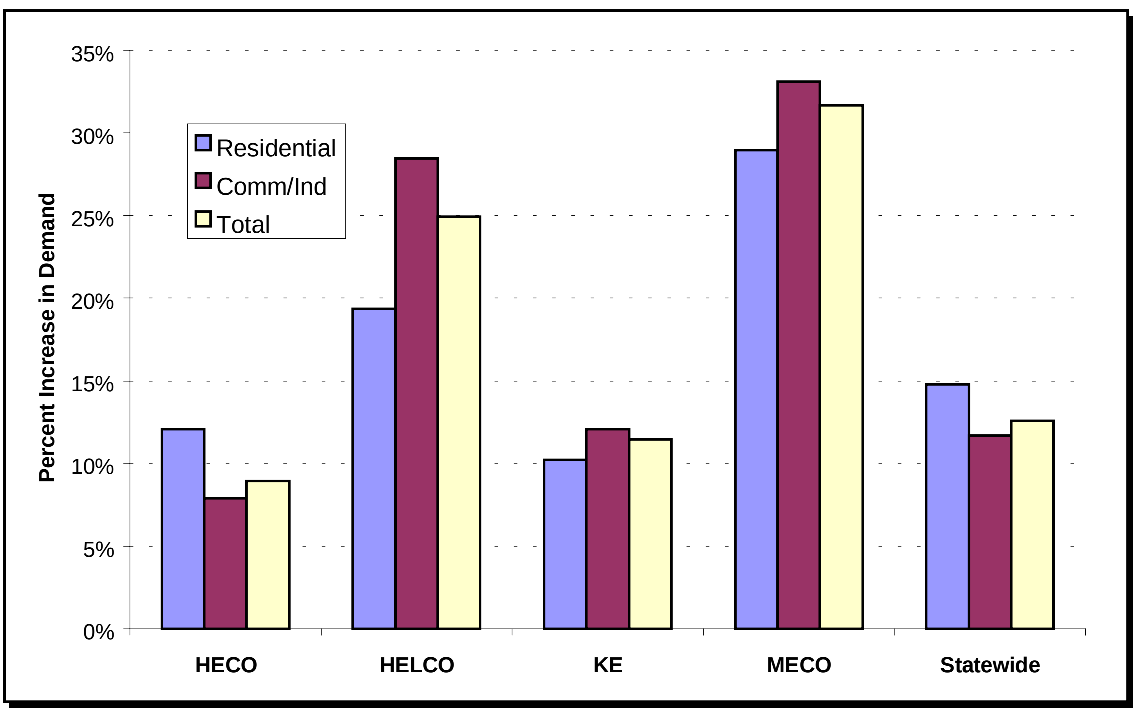
7.2.2.1 Hawaii's 1997 Average Electricity Revenues Were Nation’s Highest

Hawaii's average statewide electricity revenues were the highest in the nation in 1997. The average revenue per kWh in the United States was $0.069 (EIA 1998c, 42). In Hawaii, average revenues per kWh ranged from $0.11 for HECO to



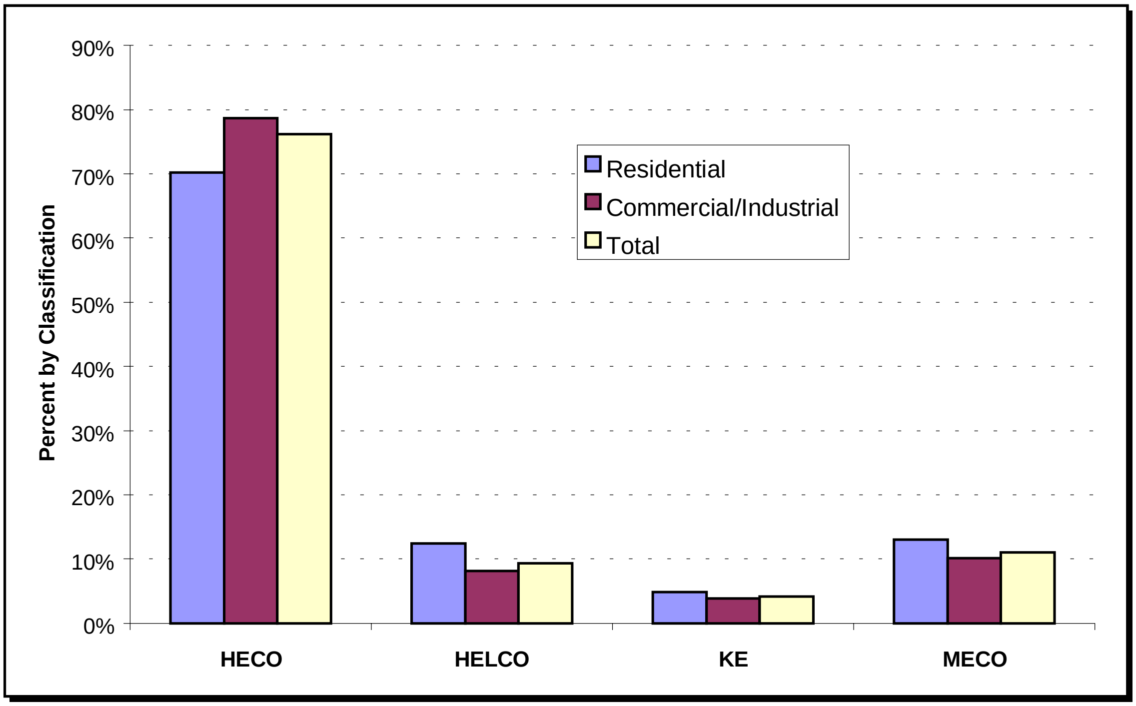
Source: Utility FERC Forms 1 and Annual Reports, 1990–1997

Figure 7.2 Electricity Sales by Hawaii Utilities (MWh), 1990–1997



Source: Utility FERC Forms 1 and Annual Reports, 1990–1997

Figure 7.3 Growth in Electricity Sales by Rate Classification, 1990–1997



Source: Utility FERC Forms 1 and Annual Reports, 1997

Figure 7.4 Percentage of Electricity Sales by Utility and Rate Classification, 1997

Table 7.1 Electricity Sales and Revenues in Hawaii, 1997

Utility	Sales (kWh)	Revenue	Average Revenue per kWh
HECO	7,049,777,000	$ 778,240,746	$ 0.110
HELCO	894,110,000	$ 160,331,960	$ 0.179
KE	382,112,000	$ 77,752,502	$ 0.203
MECO	1,028,768,000	$ 151,624,338	$ 0.147
Statewide	9,354,767,000	$ 1,167,949,546	$ 0.125

Sources: 1997 FERC Form 1 or Annual Report to PUC of each utility

$0.203 for Kauai Electric. The statewide average was $0.125 per kWh. Table 7.1 presents electricity sales and revenues of Hawaii utilities in 1997.

At about $1.17 billion, electricity revenues were 3.4% of Hawaii's estimated 1997 GSP of $34.2 billion dollars (DBEDT 1998f, Table 13.02). To the extent that electricity costs can be reduced, more money will be available for Hawaii's citizens to use for other purposes, which would benefit non-utility sectors of the economy.

Not only were Hawaii's electricity revenues the highest in the nation in 1997, electricity revenues for Hawaii utilities grew much faster than the U.S. average over the years 1990 to 1997. By 1997, revenues were 39.2% higher than in 1990 while the U.S. average was only 4.2% higher. The 39.2% increase in average Hawaii electricity revenues between 1990 and 1997 compares with an increase in the consumer price index for all urban consumers in Honolulu of only 24%. The overall U.S. consumer price index increased 23% during the same period.

7.2.2.2 Reasons for Hawaii's High Average Electricity Revenues

Some might argue that it is unfair to compare Hawaii’s electricity revenues with the lower average revenues in states that have access to less expensive energy sources, such as large-scale hydroelectric power plants, coal plants, nuclear power plants, or highly efficient natural-gas-fired, combined cycle combustion turbine generating facilities. Most power plants in Hawaii burn oil, which is more expensive than the primary mainland fuels, and which is used in only 9% of generators nationwide.

Fuel costs are not the only possible explanation – in fact, for HECO, they declined slightly from 1990 ($0.046 per kWh) to 1997 ($0.045 per kWh) (Munger 1999a, 33). Hawaii’s electricity system consists of six physically separate electricity systems. These systems are not interconnected and must operate independently. This requires each system to maintain enough excess generating capacity to ensure that electricity can be provided reliably on each of the six independent systems at all times. The costs of the units that provide this excess capacity are reflected in revenues.

In the early years of this decade, while mainland utilities added little new generation due to overcapacity, HECO, in particular, added a substantial amount of new generation. This added, through power purchase agreements with NUGs, about $0.017 per kWh of the $0.03 per kWh increase from 1990–1997 in HECO’s prices. Two of the power plants added, the AES Hawaii coal plant and the MSW-fired H-POWER unit, helped provide additional energy security for Hawaii by diversifying fuel sources (33).

The costs of DSM programs also added to prices, although customers participating in the programs had lower bills. Taxes also played a part. During the period, taxes on electricity increased by $0.003 per kWh, from $0.007 per kWh in 1990 to about $0.01 kWh in 1997 (33).

Further, the cost of living in Hawaii is estimated to be 130–135% of the urban U.S. average (Bank of Hawaii 1997, 11). These higher costs are likely reflected in many of the expenses the Hawaii utilities face in providing electricity. Additional factors increasing electricity costs included duplicative permitting requirements and processes, sunrise/sunset dates on land use applications, and floor prices in some contracts for electricity generated by non-fossil-fuel qualified facilities (Munger 1998).

Kauai Electric’s costs are relatively high compared with other Hawaii utilities, due in part to fixed costs associated with the restoration of its system after extensive damage caused by Hurricane Iniki, in 1992 (Gilman and Golden, 1999).

7.2.2.3 Electricity Prices and Hawaii's Economic Competitiveness

While Hawaii’s utilities do face higher costs, the narrowing of regional differences and coincident decrease in electricity costs occurring in Mainland power markets due to restructuring suggest the need for Hawaii to reduce its electricity costs as much as possible to enhance its economic competitiveness.

7.2.2.4 RECOMMENDATION: Review Utility Costs and Require Utilities to Report on Actions Taken to Reduce Revenue Requirements

Suggested Lead Organizations: Public Utilities Commission and Utilities

Due to the negative economic and social consequences of Hawaii's high electricity costs, the Public Utilities Commission should conduct a comprehensive review of utility costs and require the utilities to report annually on actions taken to reduce revenue requirements.

7.2.2.5 RECOMMENDATION: Continue to Examine Electricity Competition for Hawaii

Suggested Lead Organizations: Public Utilities Commission and Parties to Docket

On December 30, 1996, the Hawaii Public Utilities Commission initiated Docket No. 96-0493, instituting a proceeding to examine electricity competition and Hawaii's electricity infrastructure. Parties to the Docket submitted position statements to the Commission on October 19, 1998. Electricity Competition and Hawaii are discussed in greater detail in Chapter 9 of this report.

7.2.3 Greenhouse Gas Emissions from Electricity Generation

Greenhouse gas emissions from electricity generation produced 41% of Hawaii's 1990 baseline emissions, contributing to global warming and climate change (DBEDT 1997a). Estimated future emissions, by utility system, are shown in Figure 7.5. The emissions include those from utility-owned generation and non-sugar industry, non-utility generators. The Kyoto target for the combination of the four electricity systems (7,117,000 tons CO_2-equivalent) is shown for reference only. This is not intended to imply that any one sector, utility, or even state would be expected to meet the target by itself if the Protocol is ratified. However, the emissions under current plans were forecast to be 38% above the Kyoto target, at 9,857,000 tons, by 2010 and 48%, or 10,552,000 tons, above the target by 2020.

7.3 Changing Ownership of Electricity Generation

In 1990, Hawaii's utilities produced 90.7% of the electricity sold to customers, while non-utility generators (NUGs) and sugar industry cogeneration almost equally accounted for the rest. By 1997, the utility share declined to 62% of the total, and sugar's contribution was down to 1.5%, as several sugar plantations closed, including all those on Oahu and the Island of Hawaii.

Major power purchase agreements by HECO and HELCO raised the NUG share of net generation to 37.5% of the statewide total. NUGs obtained contracts under the provisions of the *Public Utility Regulatory Policies Act of 1978* (PURPA), a federal law intended to enhance the use of renewable energy and cogeneration.

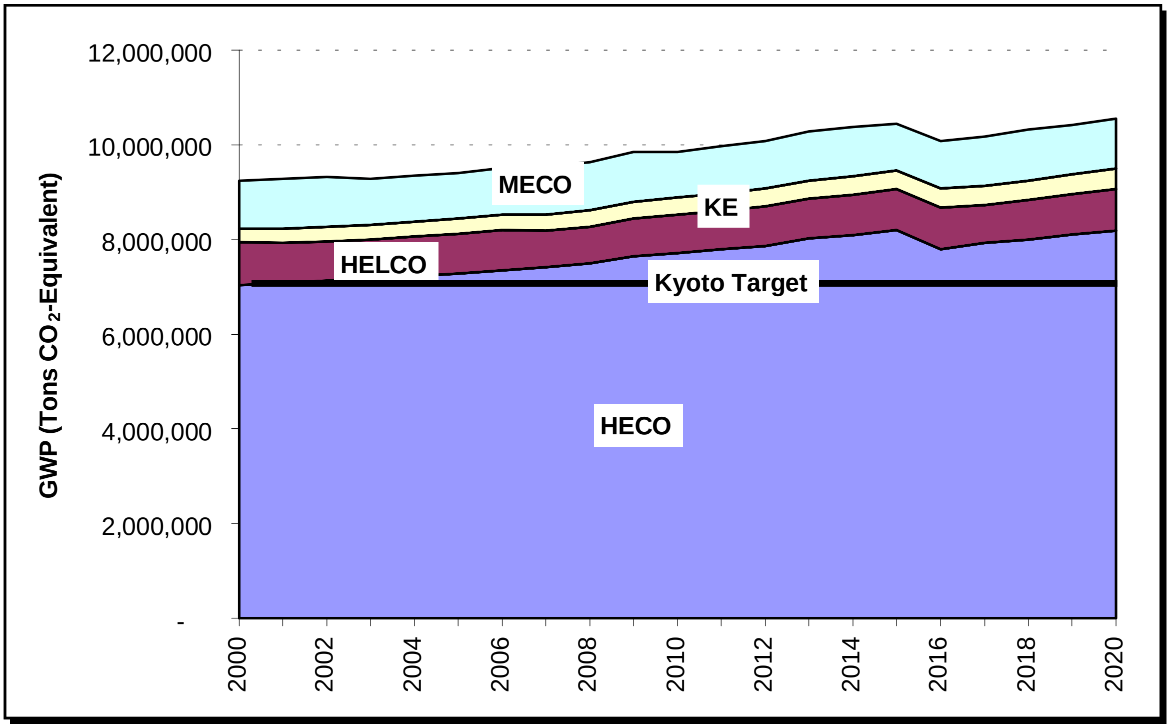


Figure 7.5 Estimated Global Warming Potential of Hawaii Electric Utility Emissions, 2000–2020

The law requires that utilities purchase from facilities qualifying under its provisions at or below the utility costs avoided by the non-utility generation. In some cases, provisions in the power purchase agreements negotiated between the utilities and their NUG suppliers have resulted, over time, in higher wholesale prices for electricity being paid by the utilities than current utility costs. While the utilities do not profit from the sales of electricity generated by non-utility generators, these costs are passed on to the consumer.

Sales under PURPA provide a form of competition, and the act has resulted in the application of advanced technology fossil fuel generation and renewable energy resources.

7.4 Fuels for Electricity Generation

7.4.1 Increasing Diversification of Fuels

In this decade, Hawaii’s electricity system became increasingly diversified, consistent with the State’s energy objective of greater energy security. As recently as 1991, over 92% of the electricity sold in Hawaii by the four electric utilities was generated using oil. Figure 7.6 shows the fuel and energy sources used to generate electricity in 1997. Solar water heating is not included as a generation source, but its use reduces the need for generation. Table A.19, in

Appendix A, details the significant diversification of the fuels used to generate electricity since 1990.

7.4.2 Renewable Energy

Another State energy objective calls for increasing the use of indigenous energy supplies. During the period 1990–1997, overall renewable energy use for electricity generation did not increase, but the shares of the various resources changed, principally due to the decline in wind generation and sugar industry electricity. The other renewables, especially geothermal and municipal solid waste, largely filled the void.

As Figure 7.6 depicts, while the percentage of oil use had been reduced to 76.5% in 1997, just over 92% of Hawaii's electricity was still generated using fossil fuels – oil and coal.

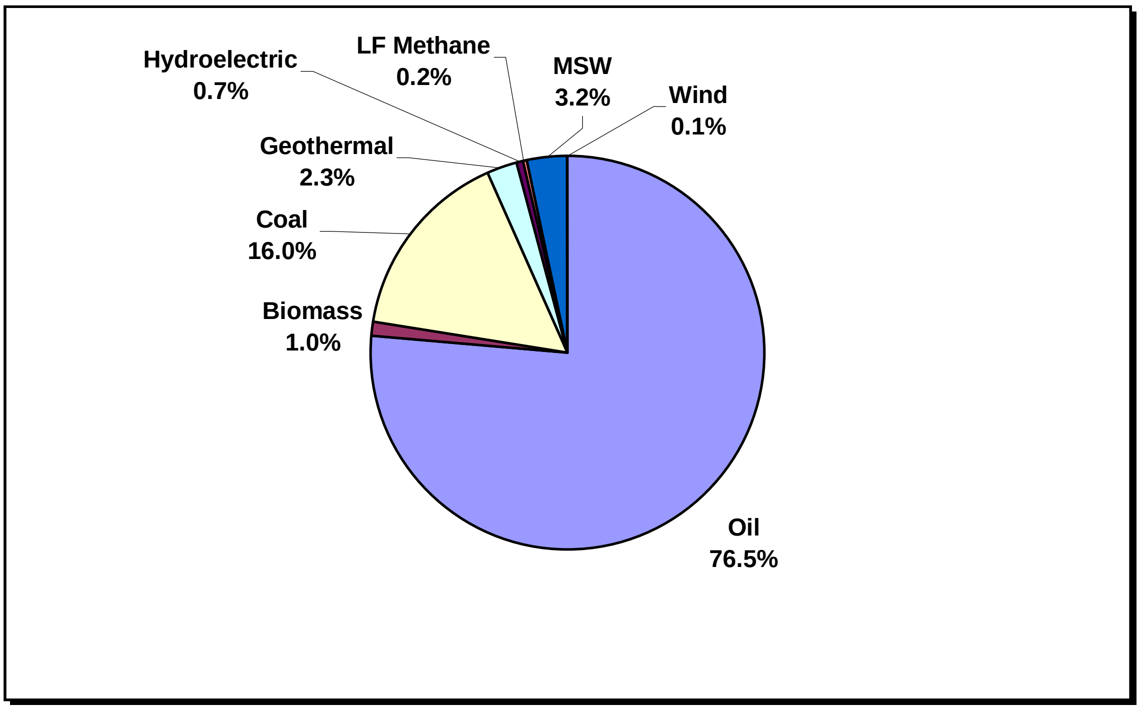


Figure 7.6 Percentage Share of Fuels Used for Electricity Generation in Hawaii, 1997

7.4.3 Recommendations for Electricity Fuels

7.4.3.1 RECOMMENDATION: Continue Diversification of Fuels Used for Electricity Generation in Hawaii

Suggested Lead Organizations: Electric Utilities and NUGs

Greater diversification of fuels in the electricity sector holds the promise of making the greatest contribution to reducing Hawaii's over-dependence on oil. In addition, renewable energy is important for offsetting fossil-fuel energy requirements (see the next recommendation and Chapter 8). Coal is the principal fossil fuel alternative, but coal produces 20% more CO_2 per unit of energy than

oil. Consequently, the economics of importing liquefied natural gas (LNG) should be monitored in case they become favorable for LNG use in Hawaii. Even more important, factors relating to the resolution of safety concerns should be monitored.

7.4.3.2 RECOMMENDATION: Increase Renewable Energy Use for Electricity Generation in Hawaii

Suggested Lead Organizations: Electric Utilities and NUGs

While a number of renewable energy projects have been proposed and are in various stages of development, it is not clear which will be deployed. Chapter 8 presents recommendations for specific renewable energy projects in each County. In addition, ways to encourage deployment of renewable energy systems, such as removing existing barriers, are discussed.

7.5 Integrated Resource Planning and Increased Efficiency

Integrated Resource Planning (IRP) is an approach to regulated utility planning that evaluates all potential energy options, including supply-side options (energy-production by conventional fuels and renewable energy resources) and demand-side management (energy conservation, efficiency, and load management). IRP also considers the social, environmental, and economic costs of these options. The goal is to meet consumer energy needs efficiently and reliably at the lowest reasonable cost.

In 1992, the Public Utilities Commission's A Framework for Integrated Resource Planning detailed the goal, governing principles, responsibilities, and requirements for IRP in Hawaii (PUC 1992). The Framework stated the goal as follows:

> The goal of integrated resource planning is the identification of the resources or the mix of resources for meeting near and long term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost (3).

In 1993, the utilities filed their first IRPs for PUC approval. Each utility was to conduct a major review of its IRP every three years, adopting a new 20-year time horizon with each cycle. The second round of IRPs was delayed for a variety of reasons, but the second IRP for KE was submitted in April 1997. HECO filed its second IRP in January 1998, and HELCO completed its second IRP in September 1998. MECO was to file its second IRP in September 1999 but asked for a delay to May 2000 to allow additional analysis. KE began work on its third IRP in August 1999.

Each plan details the utility's plans to meet the forecast energy demand for its service area over the following 20 years. The plan includes a forecast, supply-side options, demand-side options, a description of the analysis and basis for the plan, and a five-year action plan. In their IRP processes, the utilities have developed DSM programs, have more efficient resource plans, and at least formally consider renewable energy options and the externalities of various plans.

7.6 Electricity for the Island of Oahu

HECO is the electric utility serving the people of Oahu. HECO generates most of the electricity sold to its customers, but of all Hawaii utilities, HECO purchased the largest percentage (42.5%) of net generation (before transmission and distribution losses) from non-utility generators. HECO is also the parent company of HELCO and MECO.

7.6.1 Oahu's Electricity Supply

7.6.1.1 HECO-Owned Generation

HECO currently owns and operates power plants at Kahe Point, Waiau, and in downtown Honolulu. In 1997, HECO's total sales were 7,049,300 MWh, or about 75% of all electricity sold in the state. HECO's own generators produced 60% of this total, or 4,265,844 MWh.

Oil-fired steam units (OFS) burning low-sulfur fuel oil (LSFO) or No. 6 fuel oil made up 92% of HECO's units. Two units totaling 102 MW were diesel-fired (low-sulfur No. 2 fuel oil) combustion turbines (CT) used primarily to meet peaks in demand. Table A-20 provides more detailed information on HECO-owned generation units in operation at the end of 1998.

7.6.1.2 Non-Utility Generation Sold to HECO

Non-utility generators generated 3,158,415 MWh for HECO in 1997, accounting for the remaining 40% of sales. AES Hawaii operates a 180 MW atmospheric fluidized bed combustion (AFBC) coal plant that produces electricity for sale to HECO and provides steam for use as process-heat to the Chevron USA refinery. The H-POWER plant burns municipal solid waste (MSW), selling electricity to HECO and using electricity to process the waste into fuel. Kalaeloa Partners' 180 MW dual-train combined cycle unit (DTCC) uses LSFO to generate electricity. Waste heat from the two combustion turbines provides steam used in a steam recovery generator to produce additional electricity. Excess steam is provided to the Tesoro Refinery for process heat.

The Tesoro Refinery and Chevron USA refineries use oil, gas, and refinery by-products to generate electricity in combustion turbines. Most of the electricity generated by the refineries is used for internal operations, but some surplus electricity is sold on an as-available basis to HECO. Landfill (LF) methane is used as a fuel for Kapaa Generating Partners' combustion turbine. Waste heat is provided to the nearby Ameron Quarry to dry quarry products. In addition, through July 1998, Waialua Power operated a 12 MW, former sugar mill steam generator using waste oil and greenwaste for fuel. Waialua Power sold 15,310 MWh to HECO in 1997. Table A.21, lists the non-utility generators providing electricity for HECO that were operational in 1998 and their sales to HECO in 1997.

7.6.1.3 HECO System Energy Sources

Figure 7.7 summarizes the energy sources used to generate electricity for sale to HECO customers in 1997. HECO used the smallest percentage of renewable energy of the four Hawaii electric utilities – only about 4.7%.

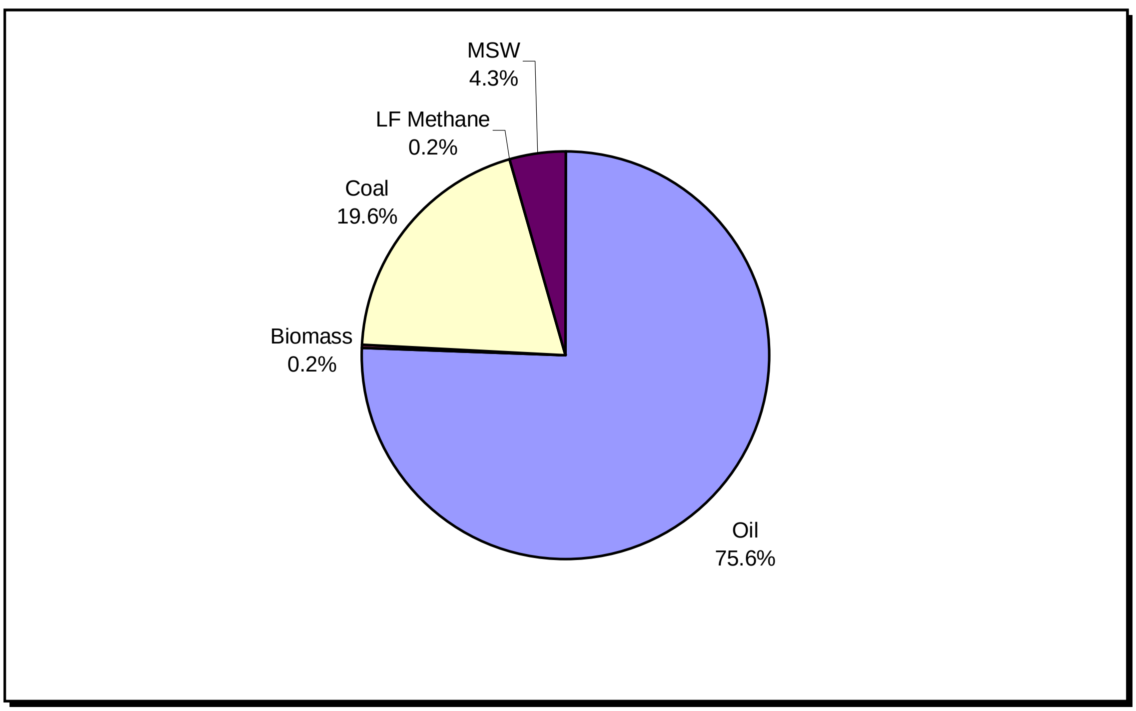
7.6.2 HECO's Integrated Resource Plan, 1998–2017

HECO filed its second IRP for the period 1998–2017 (also called IRP-97) in January 1998. The following is a brief summary of HECO's preferred plan.

7.6.2.1 Electricity Demand on Oahu

Figure 7.8 shows HECO's peak demand and sales forecasts for IRP-97 extrapolated to 2020. The forecast accounted for the expected results of DSM programs. The extrapolated HECO forecast was for a 425 MW increase in peak demand from 2000 to 2020 – a 34% increase to a total of 1,668 MW. The extrapolated sales forecast projects 9,189 GWh sales in 2020 – 31% growth.

HECO's plan was based upon the continued operation of all current HECO-owned generating units (1,263 MW). The HECO plan adds 48% more capacity (605 MW) to the current system. 70% of the added capacity was planned to be diesel-fired, and 30% coal fired.



Note that values do not equal 100% due to rounding.

Figure 7.7 HECO System Energy Sources, 1997

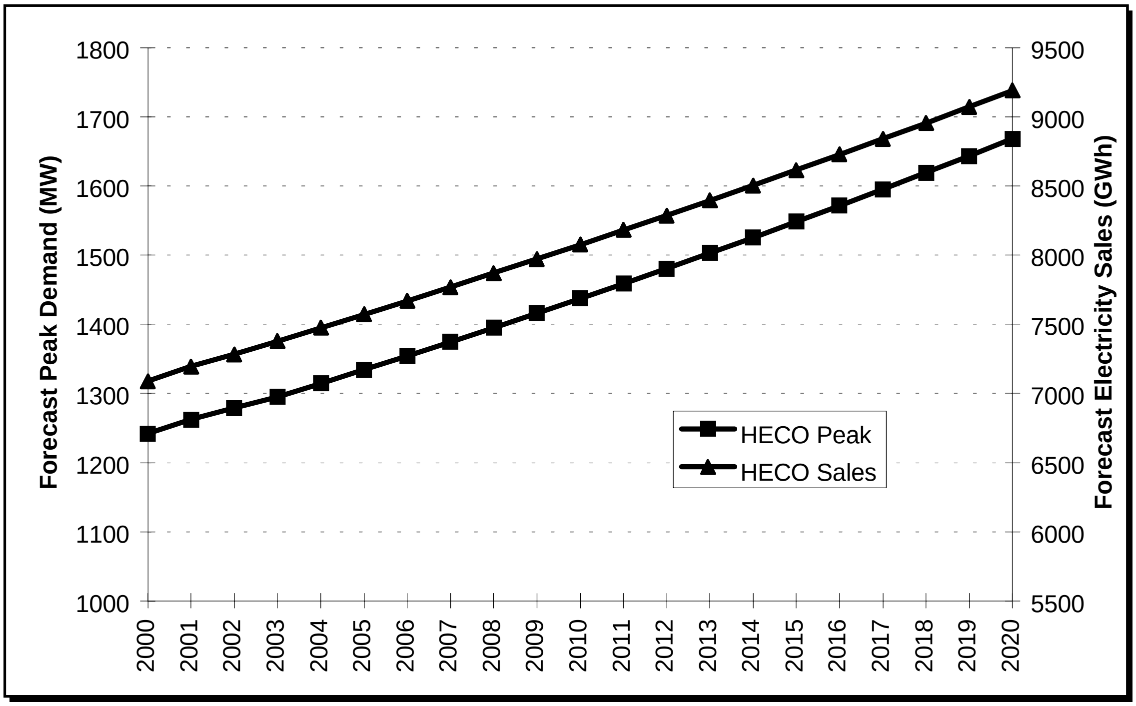


Figure 7.8 HECO Peak Demand and Electricity Sales Forecasts, 2000–2020

7.6.2.2 HECO Supply-Side 20-Year Resource Plan

The main features of HECO's supply-side resource plan are depicted in Table 7.2.

Table 7.2 HECO Supply Resource Plan, 1998-2017

	Additions		Retirements	
Year	**Capacity (MW)**	**Type**	**Capacity (MW)**	**Type**
2009	107	Phase 1 CT of DTCC		
2013	107	Phase 2 CT of DTCC		
2016	284	Phase 3 - 104 MW STG of DTCC: 180 MW AFBC	180	Kalaeloa DTCC
2017	107	SCCT		(contract expires)
Total	**605**		**180**	

Abbreviations: AFBC, atmospheric fluidized bed coal; CT, combustion turbine; DTCC, dual-train combined cycle; MW Megawatt; SCCT - simple cycle combustion turbine; STG - steam turbine generator.
(HECO 1998b, ES-3)

The new units will improve the efficiency of the HECO system. HECO's 1997 heat rate for existing HECO-owned units, which are planned to remain in service through 2020, was 11,241 Btu per kWh. Heat rates for the new units will depend upon their use. Of the planned baseload units, the 318 MW DTCC will have a heat rate of 8,170 Btu per kWh when all three phases are completed in 2016, and the heat rate of the 180 MW AFBC coal plant (to be added in 2016) will be 10,790 Btu per kWh. The 107 MW simple-cycle CT, (to be installed in 2017) is planned for operation as a peaking unit. Its heat rate will vary, depending on how the unit is operated, from 11,830 to 19,950 Btu per kWh. HECO estimated that its 2017 system efficiency will be 10,836 Btu per kWh, a 3.6% improvement over 1997 (11-32).

7.6.2.3 HECO Supply-Side Five-Year Action Plan

No generation units will be built during the five-year action plan period. Future IRPs, developed at three-year intervals, could significantly modify the 20-year plan. The main activity during the next five years will be planning and engineering for the first phase 107 MW CT to be installed by 2009 (ES-15).

Under the Action Plan, HECO has planned actions that could lead to increased renewable energy use. When the IRP was completed, HECO was negotiating with two renewable energy developers for wind and solar projects. As part of the Action Plan, HECO stated its intention to develop a Renewable Request for Proposals (RFP) for supplemental wind and/or photovoltaic energy on Oahu. The IRP called for award of a contract by January 2000, if winning bids were received (2-14 to 2-16). However, HECO did not issue an RFP in January 1999 because "the only realistic site, Kahuku, was not available for the RFP, in addition, the cost of an IRP process is significant and not warranted without the likelihood of viable projects" (Hashiro 1999).

In addition, HECO "will continue its commitment to assist in renewable energy development as presented in the PUC Renewable Energy Resource Investigation, Docket 94-0226 (HECO 1998b, 12-16). The actions include:

- Use of solar DSM programs to shift load to off-peak periods;
- Working with DBEDT to streamline the renewable energy permitting process;
- Purchase of energy from cost-effective renewable energy projects;
- Participate in and monitor renewable energy RD&D;
- Develop and implement a limited number of RD&D projects targeted to Hawaii-specific barriers;
- Implement a "green pricing" program through which customers can elect to pay more for renewable energy;[a] and
- Improve evaluation and consideration of the benefits of renewable energy in the IRP process (12-17 to 12-19).

[a] HECO's "Sunpower for Schools" project installed 2 kW photovoltaic systems at Kaimuki High School in 1997; Waianae, McKinley, Campbell, and Waipahu High Schools in 1998; and Mililani, Waialua, and Castle High Schools in 1999. These were funded by voluntary customer payments as a form of "green pricing."

7.6.2.4 HECO Demand-Side Management (DSM)

DSM is defined as any utility activity aimed at modifying the customer's use of energy to reduce demand. It includes conservation, load management, and efficiency programs. DSM offers the potential for lower customer utility bills, deferral of major power plant investments, reduced environmental impacts, and potential diversification of resources (NEOS 1995, ES-1). All of these potential benefits support the state's energy objectives. HECO's DSM plans are discussed further in Chapter 11.

7.7 Electricity for the Island of Hawaii

Hawaii Electric Light Company, Inc., (HELCO) is the electric utility serving the Island of Hawaii. HELCO's sales of 894,110 MWh in 1997 ranked third of the state's four utilities. HELCO generated most of the electricity sold to its customers, but purchased 37.6% of net generation from NUGs in 1997.

7.7.1 The Island of Hawaii's Electricity Supply

7.7.1.1 HELCO-Owned Generation

HELCO produces 150.3 MW of firm power using 69 MW of medium-sulfur fuel oil (MSFO)-fired steam generators (OFS), 38 MW of internal combustion (IC) diesel engine generators, and 43.3 MW in combustion turbine (CT) units fueled with diesel oil. In addition, HELCO is the only utility in the state that currently operates its own renewable resources. HELCO owns 3.35 MW of run-of-the-river hydro and 2.28 MW of wind generation, both used for supplemental power.

The OFS units provided 64% of the electricity generated by HELCO units in1997, the diesel units produced 32%, and HELCO's wind and hydro units provided 4%. Table A.22 details HELCO-owned generation in operation at the end of 1998.

7.7.1.2 Non-Utility Generation for Sale to HELCO

NUGs provided an additional 52 MW of firm capacity. Puna Geothermal Venture (30 MW geothermal nominal, derated temporarily to 24.5 MW at end of 1998) and Hilo Coast Power Company (HCPC) (22 MW coal-fired steam). Together, these companies provided 25% of the 202.3 MW of firm capacity available on the Island of Hawaii at the end of 1998.

Apollo Energy, at South Point, provided 7 MW of supplemental wind energy. Wailuku hydro provided 11 MW of run-of-the-river hydro, while other small wind and hydro units added 0.4 MW. Table A.23, depicts Hawaii County non-utility generators in 1998 and their 1997 sales to HELCO. Figure 7.9 summarizes the HELCO's energy sources in 1997.

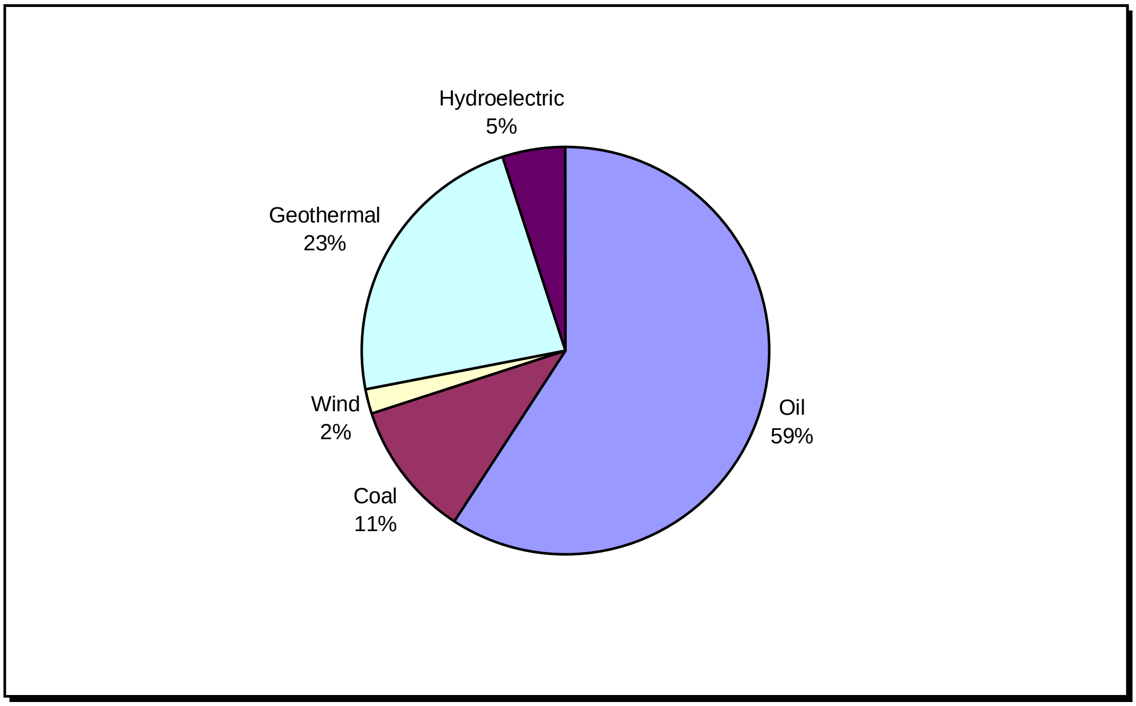


Figure 7.9 HELCO System Energy Sources, 1997

7.7.2 HELCO's Integrated Resource Plan, 1999–2018

HELCO filed its second integrated resource plan for the 20-year period 1999–2018 (IRP-98) on September 1, 1998. At this writing, in 1999, due to HELCO's inability to resolve permitting and other issues, construction had not started on generation units at Keahole that HELCO had assumed would be in place in late 1998 as a basis for their IRP. Nevertheless, this discussion will be based upon HELCO's IRP, with the expectation that HELCO will seek to adhere to their IRP as closely as possible in the future. There is no assurance, however, that the Keahole units will ever be installed.

7.7.2.1 Electricity Demand on the Island of Hawaii

HELCO forecast peak demand and sales through 2018 in IRP-98. These forecasts, presented in Figure 7.10, were extrapolated from 2018 to 2020, the *HES 2000* plan period.

7.7.2.2 HELCO's Current Supply Situation

HELCO's first IRP, issued in 1993 (IRP-93), called for installation of CT-4 and CT-5, 20 MW combustion turbines at Keahole in 1995. In 1997 these were to be connected to a steam turbine generator that would produce an additional 18 MW. HELCO also indicated that it would consider installing a 10 MW battery storage unit in 1995 as a contingency for delays in installing the Keahole generators. IRP-93 noted that the battery storage unit "could provide much needed-frequency control, voltage support, and on-line reserve for West Hawaii, as well as providing up to 10 MW of peaking capability" (HELCO 1993b, 5-7).

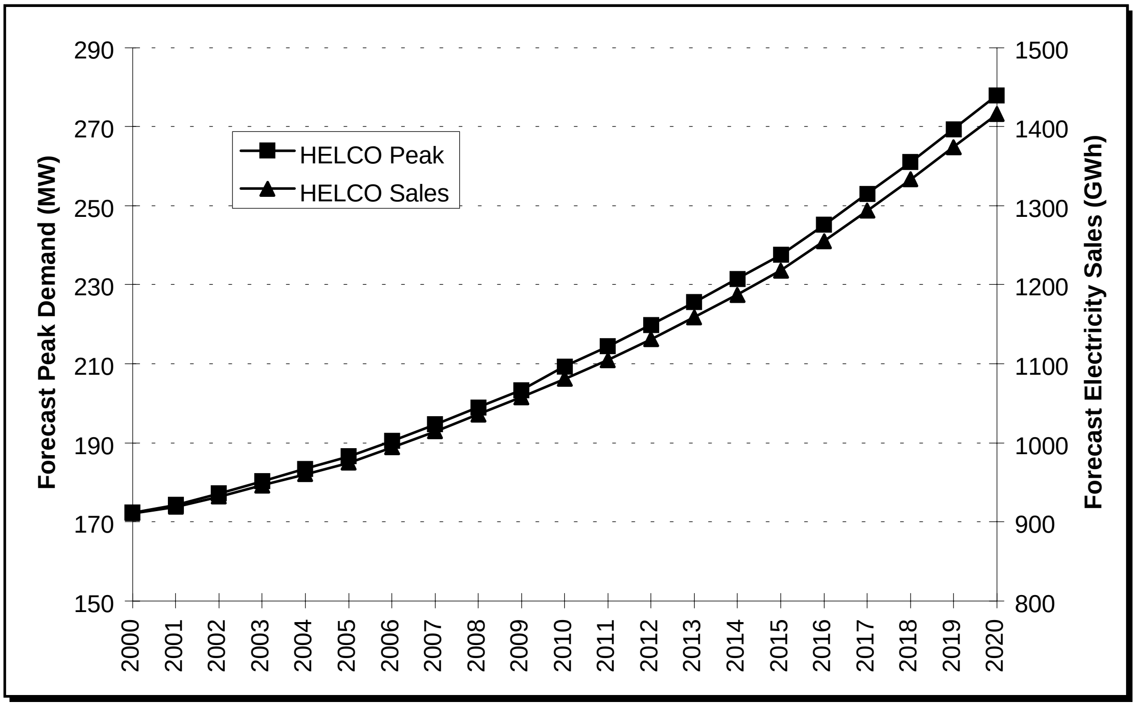


Figure 7.10 HELCO Peak Demand and Electricity Sales Forecasts, 2000–2020

None of the units planned in IRP-93 were installed due to permitting delays on the Keahole CTs and HELCO's decision not to deploy the battery storage unit. As the delays continued, on January 26, 1996, the Public Utilities Commission issued Order No. 14505 requiring HELCO to provide an assessment of its generating needs and capabilities for the period 1996–1998. HELCO's first assessment, issued in March 1996, and five subsequent updates, have been contingency plans discussing what the utility was doing and could do to ensure adequate reserve margins in the face of delays in adding new firm capacity (HELCO 1999a, i).

In IRP-98, HELCO intended to install Keahole CT-4 and CT-5 in December 1998, with the addition of ST-7 in 2006. It is not clear when HELCO will be permitted to install additional units at Keahole.

HELCO's preferred IRP also assumed that Encogen, a non-utility generator, would install a 62 MW DTCC cogeneration facility near Haina, Hawaii. IRP-98 projected installation of the first unit of Encogen's plant by April 1999, based upon an August 1998 approval. Approvals were received in 1999. Construction is underway, and the plant will be in operation in 2000.

HELCO proceeded with CT-4 and CT-5 in parallel with the Encogen contract to increase the likelihood of being able to continue to provide reliable power to Big Island customers (HELCO 1998b, 4-15). At present, neither project can be built without additional approvals from regulatory authorities.

7.7.2.3 HELCO's Fifth Contingency Plan

HELCO has successfully maximized available generation by careful scheduling of generation unit overhauls and maintenance. HELCO deferred planned unit retirements, purchased increased power from Puna Geothermal Venture and

HCPC, and obtained load management contracts to reduce the evening peak by 7 MW (HELCO 1999a, i). HELCO has also initiated a variety of DSM programs (discussed in Chapter 11) and has applied to rezone the Puna Power Plant parcel for possible expanded use if neither planned project is successful. HELCO's efforts to continue to meet electricity demand were aided by the slowdown in the Big Island's economy and reduced growth of electricity demand.

HELCO continued to seek an air permit for its Keahole units. Should this and other issues be favorably resolved, HELCO estimated that the delay on the Keahole units could exceed a year from the expected service date of December 1998. The first two phases of the Encogen facility should be installed in April and August 2000 (iii). In addition, HELCO is negotiating with HCPC and Kawaihae Cogeneration Partners for possible power purchase agreements. According to HELCO, "HELCO continues to pursue, in parallel, the installation of its Keahole Project . . . as well as power purchased from Encogen. This strategy increases the likelihood of providing reliable electrical power to the residents of the Big Island" (iv).

HELCO's contingency actions have sought to ensure adequate reserve margin (the difference between system generating capacity and peak system load). It also seeks to ensure a positive load service capability (LSC) margin that allows for planned maintenance plus the loss of the largest generating unit on line. According to *HELCO's Contingency Plan Update* (HELCO 1999b), HELCO's forecast lowest projected reserve margin for 1999 would be 21.1 MW at the day peak and the lowest LSC margins will be –3.4 MW at the day peak. In 2000, the lowest projected reserve margin will be 2.6 MW at the day peak and the lowest LSC margin will be –19.3 MW at the evening peak, if Encogen Phase 1 is not in service.

Encogen has received approval for their air permit and their power purchase agreement. It is anticipated that they will have their full 60 MW of generation on line in late 2000 (Munger 1999a).

7.7.2.4 HELCO Supply-Side 20-Year Resource Plan

HELCO's IRP-98 was not initiated as planned, but it formed the basis for five alternative cases that HELCO filed with the Public Utilities Commission as a *Supplement to September 1, 1998 Integrated Resource Plan* on March 1, 1999 (HELCO 1999a). A *Revision to Supplement to September 1, 1998 Integrated Resource Plan* (HELCO 1999b) was filed with the Commission on June 16, 1999. The Supplement is discussed in the following section.

7.7.2.5 HELCO's Supplement to IRP 1998

Faced with delays in implementing IRP-2's Action Plan, as noted above, HELCO developed five combinations of potential generation additions. HELCO selected a preferred case – Case 4. The following summarizes the HELCO Supplement Case 4 Preferred Plan, as described in the June 1999 Revision. It is depicted on Table 7.3.

Table 7.3 HELCO Revised Supply Resource Plan, 1998-2017

	Additions		Retirements	
Year	**Capacity (MW)**	**Type**	**Capacity (MW)**	**Type**
2000	62	Encogen DTCC	23.9	Waimea D8-10,12-14; Kanoelehua 11,15-17; Keahole 18-19; Shipman 1 OFS
2001	40	Keahole CT-4, CT-5	16	Keahole D20-23; Kanoelehua CT-1
2001			15.5	Puna OFS on standby
2003	15.5	Puna OFS from standby		
2005			7	Shipman 3 OFS
			22	HCPC contract expires
2006	18	Keahole ST-7		
2008			7.7	Shipman 4 OFS
2009	21.3	W. Hawaii Ph 1 of DTCC		
2013	21.3	W. Hawaii Ph 2 of DTCC		
2015			14.1	Hill 5 OFS
2016	19	W. Hawaii Ph 3 of DTCC		
2017	21.3	W. Hawaii Ph 1 of DTCC		
2019			18	Keahole CT-2
2020	21.3	W. Hawaii Ph 2 of DTCC		
Total	**239.7**		**124.2**	

Abbreviations: CT, combustion turbine; DTCC, dual-train combined cycle; HCPC, Hilo Coast Power Company; MW, Megawatt; OFS, oil-fired steam (HELCO 1999b)

Case 4 modified HELCO's IRP 1998 preferred plan by changing the Keahole and Encogen in-service dates and related retirements to reflect the new situation. It assumed that the full Encogen 62 MW DTCC would be installed by August 2000, and that the Keahole CT-4 and CT-5 (40 MW total) would be installed by March 2001. The existing HCPC power purchase agreement was assumed to end on December 31, 1999. Unit retirements were also altered as needed.

7.7.2.6 HELCO Demand-Side Management (DSM) 20-Year Plan

HELCO's DSM plan is detailed in Chapter 11.

7.8 Electricity for Kauai

The Kauai Electric Division (KE) of Citizens Utilities Company is the investor-owned electric utility serving electricity customers on Kauai. KE sold 382,112 MWh of electricity in 1997, making it the smallest of Hawaii's utilities. This represented 4% of total statewide electricity production. KE generates most of the electricity sold to its customers, but purchased 18% of net generation (before losses) from NUGs in 1997.

This section describes Kauai's electricity supply at the end of 1998, including KE generation, the NUGs that sell power to KE, and renewable energy use. It is intended to provide the reader with a better understanding of Kauai's electricity system and future plans. Electricity production and fuel use statistics for 1997 are cited here since 1998 statistics were not available when this was written.

7.8.1 Kauai's Electricity Supply

7.8.1.1 KE-Owned and Non-Utility Generation Sold to KE Customers

KE-owned generators are all located at Port Allen and provided 96.55 MW, or 87% of the firm capacity on the system. Amfac East's Lihue Plantation provided an additional 14 MW, or 13% of capacity. Other sugar plantations provided as-available power from their steam-bagasse/oil power plants and hydroelectric generators. Table A.24 lists utility and non-utility generation serving the County of Kauai.

In 1997, KE used oil fired steam (OFS) generators to produce 14% of its electricity, and both combustion turbines using diesel fuel and internal combustion diesel generators (IC-Diesel) to produce 68% of the electricity sold. The remaining 18% was purchased from Lihue plantation and other sugar companies.

7.8.1.2 KE System Energy Sources

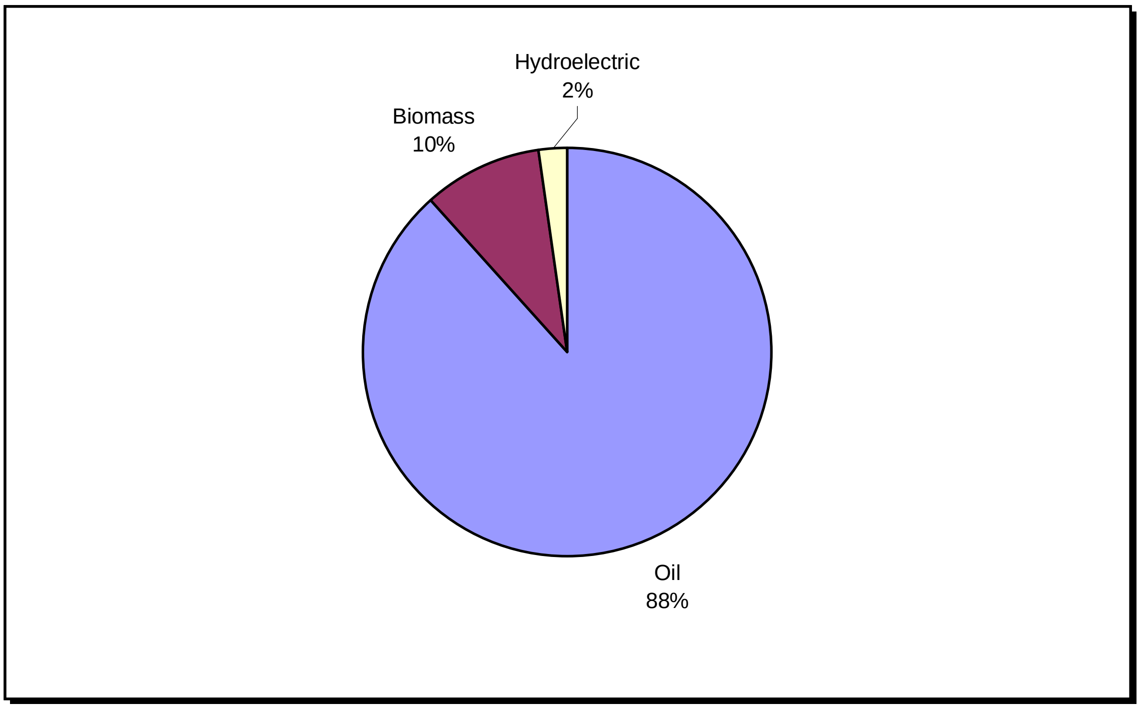


Figure 7.11 KE System Energy Sources, 1997

Figure 7.11 summarizes the energy sources used to generate electricity for sale to KE customers. On a percentage basis, KE ranked second for use of renewable energy in 1997, obtaining approximately 10% of its electricity from bagasse and 2% from hydroelectricity. The remaining 88% was produced using diesel fuel. No. 6 residual fuel oil has not been used on Kauai since 1993 due to oil spill liability concerns on the part of KE's fuel supplier.

7.8.2 KE's Integrated Resource Plan, 1997–2016

KE filed its second IRP for the 20-year period 1997–2016 with the PUC on April 1, 1997. The following discussion is based upon that plan.

7.8.2.1 Electricity Demand on Kauai

KE forecast peak demand and sales through 2016 in their second IRP. The KE peak demand forecast was extrapolated from 2016 to 2020 to match the *HES 2000* planning period and is depicted in Figure 7.12. KE forecast sales were not available in a form useable for inclusion.

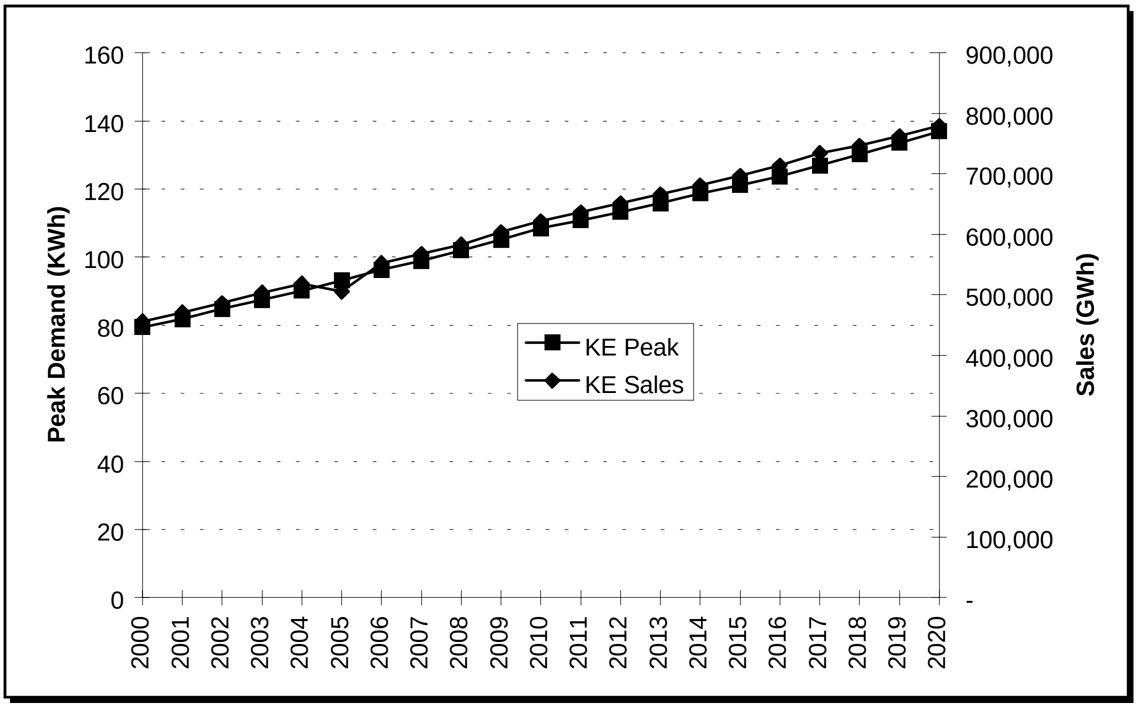


Figure 7.12 KE Peak Demand Forecast, 2000–2020

7.8.2.2 KE Supply-Side 20-Year Resource Plan

KE planned to meet its future supply through requests for proposals to NUGs to build the necessary capacity to meet their needs. KE issued an RFP in 1996 to see if an IPP could provide power at or below utility-built costs (KE 1997b, 1-5). The 1997 IRP preferred plan called for the units listed in Table 7.4 to be added during the 20-year period. KE has selected an IPP to build the first unit listed.

In the near term, Green Islands Corporation signed an energy-only contract of up to 10.3 MWh for an operation using plasma arc technology to convert Kauai’s solid waste into electricity (2-3).

KE indicated concern about the long-term viability of Lihue Plantation and its ability to continue providing 14 MW of firm power to the KE system. Flexible plans were to be prepared to deal with a closure or for if Lihue gave its 3-year notice under the existing contract (2-3 to 2-4).

Year	Capacity	Type
2002-2004	26.4 MW	Combustion Turbine with Cheng Cycle Waste Heat Recovery System
2012	10 MW	Medium Speed Internal Combustion Diesel
2014	24 MW	Coal Steam

Table 7.4 Kauai Electric Supply Resource Plan, 1997–2016

KE 1997b

Further supply-side work under the second IRP included a study to reduce NO_x from KE's existing gas turbines and an effort to consolidate air permits for the Port Allen Generation Station. KE was also to seek system heat rate improvements that would result in greater efficiency and less fuel use per kWh generated. This would also reduce emissions (2-4).

If all the firm power units proposed in the second IRP are installed, KE will have an additional 60.4 MW, increasing total capacity to 170.95 MW by 2014. This capacity would be 55% greater than the 1998 firm capacity.

While none of KE's existing generating units was scheduled for retirement, they are relatively efficient. The new units planned were expected to be slightly less (1.6%) efficient. This will be due in part to the planned use of the coal fired steam unit, which offers fuel diversity at the price of lower efficiency.

7.8.2.3 KE Demand-Side Management (DSM) Plan

Kauai Electric developed six DSM programs in its first IRP in 1993. The six programs were incorporated into the 1994 DSM Action Plan (KE 1997b, D-7). These plans are discussed in detail in Chapter 11.

7.9 Electricity for Maui, Molokai, and Lanai

The Maui Electric Company, Ltd., serves the Islands of Maui, Molokai, and Lanai. MECO is unique among Hawaii's utilities in that it operates three separate utility grids, each serving one of the three islands. MECO was the second largest utility in the state, with sales of 1,028,768 MWh in 1997. MECO generated most of the electricity sold to its customers, but purchased about 9% of net generation from NUGs in 1997.

7.9.1 Maui County's Electricity Supply

7.9.1.1 MECO-Owned Generation

MECO's Maui units included 38 MW of OFS units burning MSFO No. 6 residual fuel oil at Kahului; the Maalaea plant, containing a DTCC unit consisting of two 20 MW CT units (Maalaea 14 and 16); and Maalaea 15, an 18 MW steam recovery generator (SRG). Maalaea 17 was a 21.2 MW CT intended to be the first phase of a similar DTCC. Maalaea's DTCC and the CT total 79.2 MW. There are also 15 internal combustion diesels (IC-Diesel) at Maalaea with a total capacity of 96 MW. All values represent gross generation. Table A.25 details MECO's Maui generation at the end of 1998.

On Lanai, MECO had two 1 MW internal combustion diesels on standby at Lanai City and six 1 MW diesels and two 2.2 MW diesels at Miki Basin. On Molokai, there were eight diesels of varying sizes totaling 13.06 MW and a single 2.22 MW combustion turbine. All utility electricity on both islands was produced by MECO in 1998. Table A.26 summarizes MECO-owned generation on Lanai and Molokai at the end of 1998.

7.9.1.2 Non-Utility Generation Sold to MECO

In addition, Hawaiian Commercial & Sugar Company (HC&S) has a contract with MECO to provide 16 MW of firm power from its Puunene Mill on Maui. The Puunene Mill burned bagasse supplemented by coal to provide this power. As-available power from the Paia Mill and three HC&S hydro plants was sometimes sold to MECO on Maui. The Pioneer Mill, at Lahaina, also provided small amounts of as-available power at times. A 20 kW photovoltaic demonstration unit and two 1 kW units for school projects provided small amounts of electricity. Figure 7.13 shows the energy sources used by MECO and NUGs to generate electricity for sale to MECO customers.

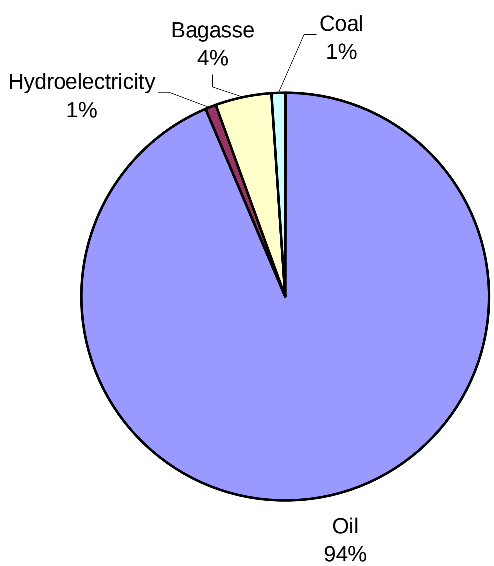


Figure 7.13 MECO System Energy Sources, 1997

7.9.1.3 MECO System Energy Sources

Energy sources on all three islands served by MECO are combined, although Lanai and Molokai use only diesel oil for their generation. On a percentage basis, MECO ranked third for use of renewable energy (5.1%). MECO used the highest percentage of oil, however.

7.9.2 MECO's Integrated Resource Plan, 1999–2018

MECO was originally scheduled to file its second IRP on September 1, 1999**.** However, in mid 1999, after conducting preliminary studies of the possibility of extending the operating life of existing units, MECO decided that this option deserved more detailed analysis in their IRP. Accordingly, MECO sought an extension to May 26, 2000 from the PUC. The MECO least-cost plan developed before the preliminary remaining useful life studies were conducted is presented below; however, a very different plan could emerge as the ultimate MECO IRP.

7.9.2.1 Electricity Demand in Maui County

Figure 7.14 shows forecast peak demand and sales through 2019, extrapolated from 2019 to 2020.

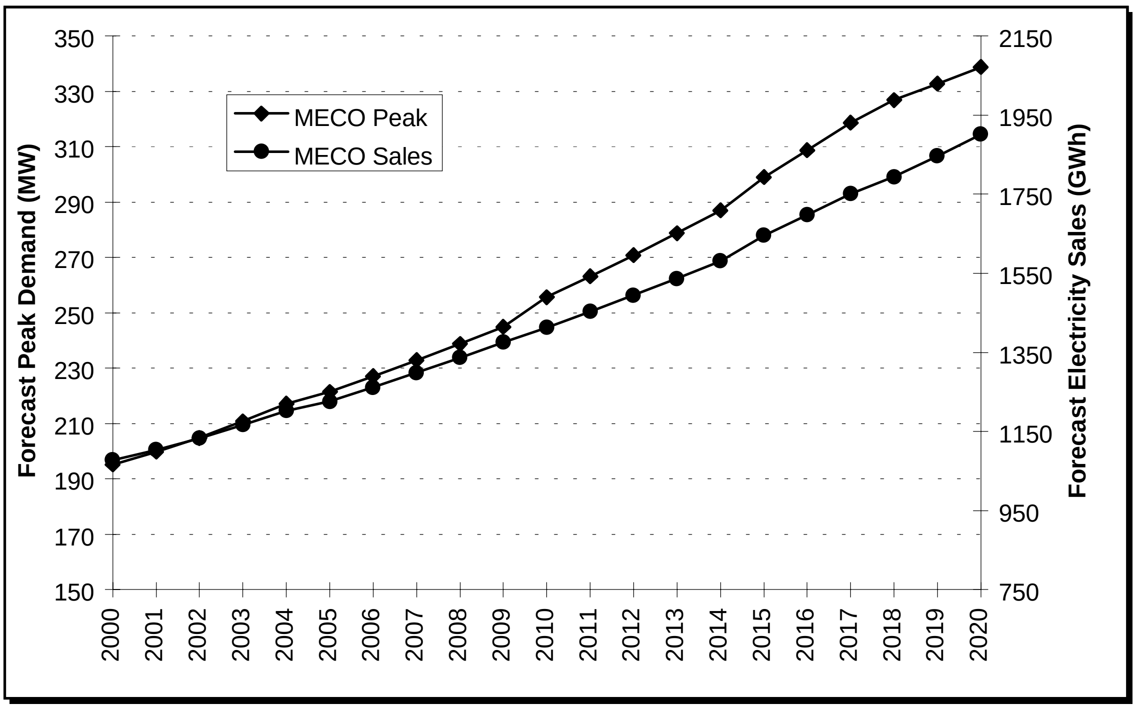


Figure 7.14 MECO Peak Demand and Electricity Sales Forecasts, 2000–2020

7.9.2.2 A Draft MECO Supply-Side 20-Year Resource Plan (1999–2018)

With three separate utility grids on three separate islands, MECO had to develop three separate plans. The plan depicted in Table 7.5 is based upon a mid-1999 draft least-cost plan. MECO's ultimate preferred plan may be considerably different. The generating capacities below are given in net generation values.

MECO planned to add 272.7 MW of new capacity by completing the Maalaea DTCC and adding four 58.7 MW DTCC at a new site. A total of 115.40 MW is to be replaced by these new units, including 96.18 MW of IC diesels, 35.92 MW of OFS units, and the expiration of the 16 MW power purchase agreement with HC&S. The planned units would be about 8% to 21% more efficient than the units they replace, depending on operating mode.

Table 7.5 MECO Preliminary Supply Resource Plan for Maui, 1999-2018

	Additions		Retirements	
Year	Capacity (MW)	Type	Capacity (MW)	Type
1999	20.8	Maalaea 19 Ph 2 CT of DTCC		
2001			16.0	HC&S Contract Expires
			2.7	Maalaea 1 Diesel
2002			5.4	Maalaea 2-3 Diesels
2003	17.1	Maalaea 18 Ph 3 SRG of DTCC	12.3	Maalaea 4-5 Diesels
2004	20.8	CT-1 Phase 1 CT of DTCC	12.5	Kahului 3 OFS
2005			18.2	Maalaea 6-7 Diesels; Kahului 1 OFS
2006	20.8	CT-2 Phase 2 CT of DTCC	6.0	Kahului 2 OFS
2007	17.1	ST-3 Phase 3 STG of DTCC	5.6	Maalaea 8 Diesel
	20.8	CT-4 Phase 1 CT of DTCC		
2008			5.6	Maalaea 9 Diesel
2009	20.8	CT-5 Phase 2 CT of DTCC	12.9	Maalaea 10 Diesel
2010	17.1	ST-6 Phase 3 STG of DTCC	12.9	Maalaea 11 Diesel
2011	20.8	CT-7 Phase 1 CT of DTCC		
2012			5.4	Maalaea X1,X2 Diesels
2013	20.8	CT-8 Phase 2 CT of DTCC		
2015	17.1	ST-9 Phase 3 STG of DTCC		
2017	20.8	CT-10 Phase 1 CT of DTCC		
2018	20.8	CT-11 Phase 2 CT of DTCC		
2019	17.1	ST-12 Phase 3 STG of DTCC		
Total	**272.7**		**115.4**	

Abbreviations: CT, combustion turbine; DTCC, dual-train combustion turbine; HC&S, Hawaii Commercial & Sugar; MW, Megawatts,OFS, oil-fired steam; STG, steam turbine generator (MECO IRP-2 Preliminary Results via Munger 1999a, 15-16)

Table 7.6 MECO Preliminary Supply Resource Plan for Lanai and Molokai, 1999–2018

	Additions		Retirements	
Year	Capacity (MW)	Type	Capacity (MW)	Type
Lanai				
2006	4.4	LL-9, LL-10 Diesels	6.0	LL1-LL6 Diesels
2008	2.2	LL-11 Diesel		
Molokai				
2006	2.2	P-10 – 2.2 MW Diesel	6.5	P1- P6 Diesels
2012			2.2	Palaau CT
2013	2.2	P-11 Diesel		

MECO 1998d; Abbreviations: CT, combustion turbine; MW - Megawatts

Lanai Supply-Side Plan. The plan developed for Lanai in the *1998 Annual Evaluation Report* (MECO 1998d) consisted of units shown on Table 7.6. The plan involved retiring six 1.0 MW IC diesels and adding three new 2.2 MW IC diesels over the period.

Molokai Supply-Side Plan. The *1998 Annual Evaluation Report* update for Molokai consisted of units shown on Table 7.6. The Molokai plan involved retiring six IC diesels totaling 6.46 MW, placing the 2.22 MW CT on standby, and adding two 2.2 MW IC diesels (MECO 1998d).

7.9.2.3 MECO Demand-Side Management Plan

MECO's DSM Plans are discussed in Chapter 11.

7.10 Siting Future Power Plants in Hawaii

7.10.1 The Need and the Dilemma

7.10.1.1 Summary of Utility Needs

Through the year 2020, Hawaii's electric utilities plan to build 1,041.4 MW of new generation, as follows:

- Oahu: 605 MW, including a 318 MW DTCC, a 180 MW AFBC coal plant, and a 107 MW simple-cycle CT;
- Hawaii: If CT4-5 and ST-7 (58MW) are built at Keahole, HELCO plans another 104.2 MW during the period, including a 58 MW DTCC, a 62.5 MW DTCC, and the first two 21.3 MW CT phases of another DTCC;
- Kauai: 61.4 MW, including a 26.4 MW CT with heat recovery system (HRS), a 10 MW internal combustion diesel, and a 24 MW coal steam plant at the Lihue Power Station;
- Maui: 234.8 MW, including four 58.7 MW DTCCs (MECO 1997d);[a]
- New additions for Molokai and Lanai are planned for existing sites.

Table A.27, summarizes the new unit additions described in the utility plans that will require sites and provides the dates they are planned to be in operation. Generally, new sites will be needed, although there may be options to add or replace generation at existing sites. It is possible, and desirable, that alternatives to central station power plants may reduce the need to build currently planned units. Alternatives to central station power plants could include varying combinations of renewable energy, energy efficiency, and distributed generation.

Nevertheless, it is likely that a significant portion of utility-planned generation will have to be built to meet Hawaii's future electricity needs. As a result, sites for future generation are needed on all islands.

[a] (Note: This is based upon MECO's current draft least-cost plan. Additional work on their second IRP continues and may result in selection of a different plan.)

7.10.1.2 Siting Conflicts

Virtually everyone needs and uses electricity, and most people believe that new generation is fine – as long as it is “not in my back yard.” Due to concerns about air pollution, noise, dust, fuel-truck traffic, and aesthetics, few people want to live or work near – or even within sight of – a major power plant. This complicates finding suitable locations for new generation to meet future electricity needs. Locations are needed well away from almost everyone’s back yard, which, in turn increases transmission line requirements, which also face siting opposition.

7.10.1.3 Air Quality Constraints

On Oahu, HECO intends to build its next unit of generation, planned for operation in 2009, in the Campbell Industrial Park. The recent *CIP/Kahe Air Quality Assessment Study* indicated that the area could accept additional industrial growth or expansion of the industrial facilities (DOH 1999, 8-1). Nevertheless, the HECO must obtain an air permit for the project based upon the specifics of its planned emissions. Future projects will have to meet USEPA prevention of significant deterioration emission criteria and potentially higher emission standards. Accordingly, other areas may have to be considered for future generation in the second decade of the next century.

On Kauai, all KE-owned generation is now located at Port Allen. One of KE’s motivations in seeking to develop an additional site was a preliminary estimate that the Port Allen airshed could accommodate no more than about 30 MW of additional fossil fuel generating capacity without expensive retrofits or replacement of existing units.

7.10.1.4 Other Factors

Other major siting considerations include proximity to load, availability of cooling water, access to fuel transportation links, zoning, presence of endangered species or archaeological sites, and the ability to obtain necessary State and County permits.

7.10.2 Prospects for Future Sites

Kauai Electric and Maui Electric have identified future sites for generation and are involved in the permitting process. The planned facilities will provide siting for all planned new generation noted in the KE and MECO IRPs. According to their most recent IRPs, HECO is in the process of permitting a site for its first planned new unit, and HELCO is seeking a new site in West Hawaii. Both utilities will need additional sites besides these to install all planned units.

7.10.2.1 Future Sites for HECO

HECO intends to install its planned DTCC plant at HECO’s Barbers Point Tank Farm, in the Campbell Industrial Park at Kapolei. As part of its IRP action plan, HECO is seeking additional property for expansion of a related substation and the tank farm itself to accommodate the complete plant. The company is proceeding with air and land use permit activities that involve long lead-times.

HECO filed its air permit application on June 3, 1997, and expects to receive its permit by November 2006. Construction is scheduled to start in October 2007, and the Phase 1 combustion turbine is expected to begin commercial operation in simple-cycle mode in January 2009, followed by the Phase 2 unit in January 2013. With the addition of the Phase 3 steam turbine unit, operation as a DTCC is planned for January 2016 (HECO 1998b, 12-14).

It is not clear where the 180 MW AFBC coal plant planned for operation in 2016 and the 107 MW SCCT planned for operation in 2017 will be installed. If the HECO tank farm site is not permitted, HECO must obtain the necessary permits for another site by November 2006 to allow the CT to be released for manufacture (12-14).

7.10.2.2 Future Sites for HELCO

HELCO has sought a West Hawaii site since before 1988. In that year, a West Hawaii Site Study identified a number of potential sites to meet HELCO's stated need to locate new generation on the side of the island where of the new load growth will occur. HELCO encountered major obstacles in attempting to locate generation at the Puuanahulu and Kawaihae sites recommended in the Site Study. Ultimately, HELCO sought to site its next generation unit at Keahole and has pursued that goal since 1992. Additional air data is being collected as part of HELCO's efforts to obtain an air permit.

HELCO's IRP-1998 stated that "HELCO will begin efforts to select and acquire the new West Hawaii site within the five-year action plan period with the intent of securing the new site prior to initiating permitting and engineering efforts on the CT-6 unit" (HELCO 1998b, 9-7). It appears that HELCO is simultaneously negotiating for more than one site and will select the most suitable site "once the issues of concern are addressed with the landowners" (9-8). HELCO indicated in its March 1999 Contingency Plan that "specific work plans are currently being developed" (HELCO 1999a, 2).

In April 1999, the Hawaii County Council approved HELCO's request to rezone the Puna Power Plant parcel from agricultural to industrial and to amend the State land use boundary designation (Munger 1999, 17). While HELCO has no specific plan to use this site, it would be available for future generation. (2).

The permitting difficulties encountered by HELCO with its Keahole site clearly demonstrate the need to identify and permit future sites well before they may be required.

7.10.2.3 KE and the Lihue Energy Service Center

Kauai Electric is developing a master-planned energy service center in the Lihue area. The site could eventually contain 120 to 150 MW of new generating capability and a centralized transmission and distribution (T&D) facility base yard. Full build-out of the site would not occur for at least 30 years, and may not occur at all if emerging technologies such as microturbines and fuel cells, or some other form of distributed generation becomes more cost-effective than the KE's proposed central power station units (KE 1999, 2-1).

As outlined in KE's IRP-1997 and the final EIS for the Lihue Energy Service Central (KE 1999), in the 2002–2004 time frame, KE needed a new site to allow installation of the next planned generation unit, a 26.4 MW advanced steam-injected cycle combustion turbine in the 2002–2004 time frame. Should Lihue Plantation, a current supplier of electricity to KE, stop operations, the earlier installation date would be required to meet base case forecast demand.

If in the longer run, the year 2010 or beyond, alternatives to the proposed technologies for electrical generation on Kauai may become available or more economical, the continuing IRP process will identify and select such alternatives during one of the triennial planning cycles. In the meantime, DBEDT views the development of the Lihue Energy Service Center site is a prudent measure necessary to ensure timely provision of sufficient, reliable electricity to the people of Kauai.

7.10.2.4 MECO and the Waena Generating Station

MECO has proposed the Waena Generating Station as a master-planned site for up to 232 MW of new capacity (four 58 MW DTCC units) to be built in four stages. If MECO selects a plan similar to that proposed in their current draft least-cost plan, construction on the first unit would be started in 2004, and the fourth unit would be completed in 2020 (MECO 1999).

In its EIS, MECO reported that following current additions to its Maalaea facility, both Maalaea and Kahului facilities would be built to full land capacity (MECO 1997d 2-6). MECO determined that the need for additional units on the system could not be offset or postponed by planned DSM programs, potential contracts with NUGs, alternative energy, or deferred retirements of existing units (3-16 to 3-17). DBEDT concurs that at least a significant portion of the generation planned for Waena will likely need to be built to provide continuing, reliable electricity service on Maui. If alternatives to the currently proposed technologies for electricity generation become available or become more economical, the continuing IRP process will identify and select such alternatives during a future triennial planning cycle.

7.10.3 RECOMMENDATION: Identify, Designate, and Permit Energy Sites for Future Electricity Generation

Suggested Lead Organizations: Electric Utilities, Public Utilities Commission, State and County Permitting Agencies, Stakeholders

The utilities, State and County permitting agencies, and stakeholders could jointly identify and designate sufficient sites to support forecast new generation requirements for a 20-year period. Since under the current regulatory framework the Public Utilities Commission does not allow cost recovery for property held for future use if that use is more than 10 years in the future, the Commission is urged to consider extending this limit to the full 20-year IRP planning period. Permits for construction of new units would be sought on a unit-by-unit basis.

Sites would be established for fossil-fuel and renewable energy technologies. Renewable site areas would be selected based upon renewable resource assessments. Sites for other projects, such as biomass, hydroelectric, or pumped-storage hydro could be difficult to provide in advance. State and County permitting agencies should examine ways to streamline the approval process. Such improvements to the existing generation siting process are essential for meeting Hawaii's future electricity needs.

7.11 The Potential of Future Technology for Electricity Supply

7.11.1 The Need for New Approaches

Hawaii's geographic isolation helped create its dependence on fossil fuel, especially oil. As discussed above, there are likely limits to the number of current renewable energy technologies that can be used on each electrical system. In the area of firm power, biomass provides the greatest potential on all islands, but is constrained by available land for growing fuel, soil management issues, as well as by costs. On the Island of Hawaii, there is a potential for additional geothermal energy, but there are relatively low requirements at nighttime for power and cultural and health concerns to be met. A geothermal system capable of producing power that follows changing demand during the day is needed. In addition, problems with the current steam source, permits to access additional steam sources, and stakeholder concerns must be addressed.

7.11.2 Recommendations for Future Technologies

7.11.2.1 RECOMMENDATION: Continue to Pursue Greater Efficiency in Fossil Fuel Central Station Generation

Suggested Lead Organizations: Electric Utilities and NUGs

It appears that fossil fuels will continue to be used for the foreseeable future, and certainly for the 20 years covered by the strategy proposed in this document. The move by Hawaii's utilities to DTCC units consisting of two combustion turbines and a steam turbine generator is a step in the right direction. The steam turbine generator allows additional efficiencies by using exhaust heat from the combustion turbines to create steam to drive a generator, thereby producing additional power with little additional fuel use and little additional greenhouse gas emissions. The new units are generally more efficient than the units they replace or supplement.

Where fossil-fuel generation is required, Hawaii's utilities and NUGs should continue to install the most efficient generation technologies available. On the

Mainland, these are natural gas-fired DTCC systems. Unless it becomes feasible to import compressed natural gas into Hawaii, the most efficient units available for use here will likely be the latest versions of oil-fired DTCC and AFBC units.

7.11.2.2 RECOMMENDATION: Utility Integrated Resource Planning Should Consider Cost-Effective, Energy-Efficient Fuel Substitution between Electricity and Gas

Suggested Lead Organizations: Public Utilities Commission, Electric Utilities, The Gas Company

It is recommended that the IRP Framework be revised to require electric and gas utilities to consider whether the use of electricity or the use of gas most cost effectively meets end-use energy needs with the greatest energy efficiency.

7.11.2.3 RECOMMENDATION: Pursue Greater Efficiency Through Distributed Generation (Small Cogeneration, Microturbines, and Fuel Cells)

Suggested Lead Organizations: Electric Utilities, NUGs, Gas Utility, and Electricity Users

Distributed generation places small generators at the source of demand. Many evolving distributed generation technologies are highly efficient and further enhance efficiency by avoiding the line losses that would have occurred had the power come from a distant central power station. Distributed generation technologies include small combined cycle cogeneration units, microturbines, and fuel cells. These technologies should be closely monitored and encouraged.

Such policies as net metering can help encourage their use by allowing an owner of distributed generation unit to sell power to the utility system when it had excess power. This would offset the cost of power purchased from the system when the distributed unit could not meet all of the entity’s demand.

To retain customers, HECO recently sought and obtained rate provisions that allow them to offer rate discounts to customers that would be capable of installing their own distributed generation. To the extent that the discounts discourage installation of distributed generation systems that are more efficient than the utility system, this is economically and environmentally counter-productive.

As an alternative, utilities are encouraged to consider customer-owned distributed generation as a form of DSM in the same manner as solar water heating. In this context, it may be to the benefit of the utilities and society to offer DSM programs to encourage distributed generation. Utilities should also examine the potential for distributed generation as an alternative to future central station power generation.

7.11.2.4 RECOMMENDATION: Increase Use of Renewable Energy and Building Energy Efficiency

See Chapters 8 and 11 for detailed recommendations.